DRA

Division of Ratepayer Advocates
California Public Utilities Commission

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October 12, 2006

Administrative Law Judge John Wong
California Public Utilities Commission
505 Van Ness Avenue, Room 5009
San Francisco, CA 94102

Re: Southern California Gas Company's Gas Cost Incentive Mechanism (GCIM), Year 12 Results (A.06-06-017)

Dear ALJ Wong,

The Division of Ratepayer Advocates (DRA) hereby submits two copies of its Monitoring and Evaluation Report on Southern California Gas Company's (SoCalGas') Gas Cost Incentive Mechanism (GCIM) for the April 1, 2005 through March 31, 2006 period (Year 12). Since we do not have a service list as yet for this proceeding, copies of this report are being e-mailed to all parties of record in SoCalGas' Year 11 Application, A.05-06-030. Hard copies of DRA's Report, which include the workpapers are available upon request.

Sincerely,

R Ramchandani

Ramesh Ramchandani
Program Project Supervisor
Divison of Ratepayer Advocates

cc: Service List in A.05-06-030

Exhibit Number	:	
Commissioner	:	**John Bohn**
Admin. Law Judge	:	**John S. Wong**

DRA

Division of Ratepayer Advocates
California Public Utilities Commission
State of California

MONITORING AND EVALUATION REPORT

Southern California Gas Company's
Gas Cost Incentive Mechanism

April 1, 2005 through March 31, 2006
GCIM Year 12

Application 06-06-017

San Francisco, California

October 12, 2006

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CHAPTER 1

SUMMARY AND RECOMMENDATIONS

1.1 Introduction and Summary

On June 15, 2006, the Southern California Gas Company (SoCalGas) submitted its Gas Incentive Cost Mechanism (GCIM) Year Twelve (12) Application (A.06-06-017). In its Application, SoCalGas reports on the results of its Year 12 GCIM for the 12 months ending March 31, 2006. SoCalGas states that it generated cost savings of $69.1 million below Year 12 benchmark market prices.[1] According to SoCalGas, the sharing formula approved by the Commission in D.02-06-023 yields a benefit of $59.3 million for its ratepayers and $9.8 million for its shareholders. SoCalGas requests Commission approval to recover the shareholder incentive reward of $9.8 million.[2] DRA recommends that SoCalGas' request be granted, and that the SoCalGas shareholder reward be recovered by SoCalGas through the Purchased Gas Account (PGA).

The Commission's Division of Ratepayer Advocates (DRA), in this annual monitoring and evaluation report, incorporates an audit of SoCalGas' recorded PGA costs, an analysis and review of the GCIM calculations, and an evaluation of the manner in which the program operated under Year 12 market conditions. DRA's comprehensive audit of the GCIM Year 12 results, as discussed in Chapter 2 of this report, confirms that cost savings of $69.1 million below Year 12 benchmark prices were achieved by SoCalGas. DRA's review also confirmed that application of the sharing mechanism approved in D.02-06-023 results in a ratepayer benefit of $59.3 million and a shareholder reward of $9.8 million. These results are shown in Table 1-1 below:

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1 A.06-06-017, Attachment A, SoCalGas Annual Report on its Gas Cost Incentive Mechanism for the Year 12, p2.

2 A.06-06-017, p.2.

TABLE 1-1			
Summary of GCIM Reward Calculation (000's)			
Line			
1	Procurement Benchmark Commodity costs		$2,991,828
2	Less: Actual Commodity Costs		2,922,695
3	GCIM Total Savings	(line 1- line2)	$69,133
4			
5	Lower Tolerance Band @ 1 % below commodity benchmark	(Line 1 x 1%)	29,920
6	Ratepayer/Shareholder Shared Savings	(line 3 - line5)	39,213
7			
8	Shareholder Computed Reward	(line 6 x 25%)	$9,803
9	Total Ratepayer Savings	(line 6 x 75%) + (line 5)	$59,329

On the basis of these audit results, DRA recommends that the Commission authorize SoCalGas to recover its shareholder reward of $9.8 million through the PGA. Additional issues discussed in this report include SoCalGas compliance with its November 1 storage inventory targets, changes in interstate capacity holdings, and the removal of financial hedging activities from the GCIM pursuant to D.05-10-043.

1.2 Background

The GCIM program is designed to give utilities the incentive to acquire gas at the lowest possible cost and to take on some associated risks. Since its inception and subsequent approval in 1994, the GCIM program has been modified and extended a number of times by Commission Order.[3] In GCIM Years Seven, Eight, Nine and Ten, the Commission agreed with SoCalGas' request for shareholder rewards, but granted it subject to refund or adjustment as might be determined in I.02-11-040.

To achieve the GCIM objectives, the Commission allows SoCalGas to use a number of cost-saving gas procurement methods such as the physical sale of gas to third parties and hub transaction activities. Each of these is discussed in this report. Up

3 Approved in D.94-03-076. Modified and extended by D.97-06-061 for two years. Approved for extension on an annual basis for 12-month cycles in D.98-12-057. D.02-06-023 approved a Settlement Agreement that further modified the GCIM and extended it through March 31, 2001 and beyond, on an annual basis until further modified or terminated by Commission order. D.03-08-065 and D.03-08-064 approved shareholder rewards and indicated that the awards would be subject to refund or adjustment as determined in I.02-11-040.

until GCIM Year 11, SoCalGas also used financial derivatives completely within its GCIM to reduce and effectively manage the cost of gas for its core ratepayers.

The GCIM is a ratemaking incentive mechanism that was designed to provide more efficient regulatory controls than its predecessor, i.e. annual reasonableness reviews, and is intended to balance the interests of SoCalGas Company's core customers and shareholders. It provides for the measurement of SoCalGas' gas purchasing performance by weighing actual performance against a "…benchmark cost of gas intended to emulate actual market conditions on a monthly basis." For the most part, the benchmark has been based on southwest gas price indices published in the Natural Gas Intelligence, Inside FERC Gas Market Report and Natural Gas Week publications. These indices reflect a weighted combination of basin or border prices.

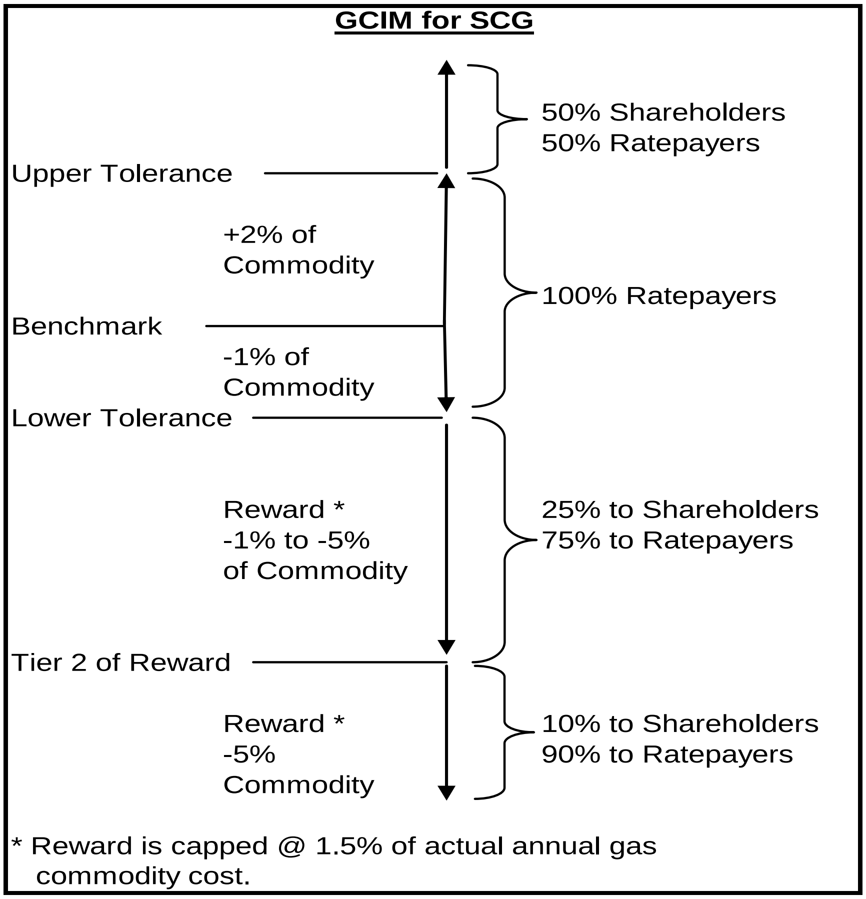
SoCalGas' GCIM provides for a tolerance band, or deadband, around the benchmark cost. The upper limit of the tolerance band is set at 2 percentage points above the benchmark commodity costs, while the lower limit of the tolerance band is set at 1 percentage point below the benchmark commodity costs. When actual costs fall within this tolerance band, any associated benefits or lack thereof accrue 100% to the ratepayers account. In this situation, shareholders are not impacted one way or the other.[4] However, when actual costs fall outside of the tolerance band, then the benefits or losses, as the case might be, are shared in different proportions between the shareholders and the ratepayers, depending on whether the actual costs are above the upper limit of the tolerance band or whether the actual costs are below the lower limit of the tolerance band.

In the event that actual gas procurement costs exceed the upper tolerance limit, the excess costs are shared 50-50 between ratepayers and shareholders. If actual costs fall between the lower 1% tolerance band but are higher than 5 percentage points below the benchmark commodity costs, the savings are shared as a 25% reward for shareholders and a 75% savings for ratepayers. If actual costs are less than 5 percentage points below the benchmark commodity costs, savings are shared as a 90%

4 D. 02-06-023 (mimeo), Dated June 6, 2002, P.4.

savings for ratepayers and a 10% reward for shareholders. Regardless, SoCalGas' total reward is capped at 1.5% of commodity benchmark costs.

Pictorially, the GCIM can be depicted as follows:



1.3 GCIM 12 Year Savings Comparison

SoCalGas achieved a total of $69.1 million in savings during the GCIM Year Twelve, ending March 31, 2006. The GCIM Year 12 savings amount is more than double the Year 11 savings of $31.0 million.   A summary of the GCIM ratepayer savings in gas costs for previous years, including this GCIM Year 12, is shown in Table 1-2. The total share of ratepayer savings in Year 12 amounts to approximately $59.3 million while the shareholder reward amounts to approximately $9.8 million, yielding the total savings of $69.1 million. The audited basis supporting these amounts is presented in Chapter 2 of this report.

TABLE 1-2

GCIM Year	Ratepayer Savings	Shareholder Reward
1	$ (1.1) million	---
2	$ 3.2 million	$3.2 million
3	$ 10.6 million	$10.6 million
4	$ 4.8 million	$ 2.0 million
5	$ 10.4 million	$ 7.7 million
6	$14.4 million	$ 9.8 million
7	$192.7 million	$30.8 million
8	$172.4 million	$17.4 million
9	$32.7 million	$6.3 million
10	$24.6 million	$2.4 million
11	$28.9 million	$2.5 million
12	$59.3 million	$ 9.8 million

1.4 Physical Hedging with Storage

DRA's review of SoCalGas' GCIM Year 12 operations indicates that SoCalGas met its November 1 core storage inventory target. The core inventory level was at 68.5 Bcf as of November 1, 2005.

In its GCIM Year 11 report, DRA recommended that SoCalGas' storage target assure the Commission that core customers are physically hedged with storage gas to the maximum extent possible. Subsequent to DRA's recommendation in that report, SoCalGas, TURN and DRA executed a Joint Recommendation to accommodate the concerns that DRA expressed in its GCIM Year 11 report. The Joint Recommendation[5]

5 The Joint Recommendation is contained in the Commission's Proposed Decision, September 13, 2006, in SoCalGas' GCIM Year 11 Application, A.05-06-030, and awaits final Commission action.

expanded on the earlier Settlement Agreement[6] that was executed in July 2001, and would change the tolerance band around the 70 Bcf target from +5/-5 Bcf to +5/-2 Bcf (excluding any net park and net loan positions). The Joint Recommendation also requires SoCalGas to secure a mid-season minimum storage inventory of 49 Bcf as of July 31, 2006.

1.5 Financial Hedging for Winter 2005-2006

In its Application, SoCalGas states that it incurred costs of $24.6 million of the $55 million that the Commission authorized for financial hedges for Winter 2005-2006. This winter hedging was performed outside of its GCIM, as authorized by the Commission in D.05-10-043. DRA's audit confirms this information provided by SoCalGas.

Prior to Year 12, SoCalGas had performed all of its financial hedging inside of the GCIM mechanism to ensure that SoCalGas had a financial incentive and motivation to optimize the performance of the financial hedges it procured. This changed in D.05-10-043, which authorized SoCalGas to perform its winter hedging outside of the GCIM mechanism. SoCalGas was authorized to procure financial hedges up to a maximum exposure of $55 million.

1.6 Interstate Capacity

There were a number of changes that took place during Year 12 in SoCalGas' interstate capacity holdings. These are described in more detail in Attachment A, Appendix C of SoCalGas' Application. DRA has been a party to the discussions and filings relating to SoCalGas' acquisition and/or reduction of interstate capacity. [7] The

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6 The Settlement Agreement, executed in July 2001 by SoCalGas, TURN and DRA,and adopted by the Commission in D.02-06-023, requires that SoCalGas meet the November 1 core storage inventory target of 70.0 Bcf of physical gas supply with an accepted variance of +5/-5 Bcf. If this target is not met, then at least 60 BCF of actual physical gas must be stored prior to December 1. Furthermore, according to D.02-06-023, hub volumes are not to be included in the target core storage inventory. Only physical gas in storage counts toward the core storage inventory target.

7 Per the procedures established in D.04-09-022, SoCalGas, DRA, TURN and the Energy Division are to work together in a consultative process for all commitments for interstate capacity.

new and renegotiated agreements are discussed in SoCalGas' Application, Attachment A, Pages 5 -7.

SoCalGas nominated similar amounts of its firm capacity (Year 12 nominations were 84% on El Paso, 81% on Transwestern, & 98% on Kern River) as in Year 11 (Year 11 nominations were 84% on El Paso, 70% on Transwestern, and 96% on Kern River). The details of SoCalGas' capacity utilization are discussed in Chapter 2, Section 2.8 of this report.

1.7 Summary of Program Evaluation

DRA's analysis showed that the SoCalGas GCIM operation in Year 12 was prudent and reasonable and provided benefits to the utility's core customers. The GCIM, as structured in Year 12, continues to be a program with positive impacts for ratepayers and SoCalGas' shareholders. The benefits of the program were stated by DRA in its report for Year 10. DRA stated:

> "With a reward linked to performance, the utility has the incentive to reduce the cost of gas purchases for the core ratepayers. In this case, the core customers obtained direct benefits from the savings achieved from the reduced cost of gas, while the utility will likewise directly benefit through a reward for a portion of the savings according to the sharing formula. Therefore, under the GCIM, the ratepayers and the utility interests are aligned…
>
> The GCIM provides the Commission, as the regulator, with appropriate objective standards against which to measure the utility's performance in undertaking gas procurement and transportation functions on behalf of core customers. The monthly published price indices are public information. The calculations for the monthly commodity reference benchmark prices are clear and transparent. The monthly GCIM reporting requirements enable monitoring and tracking of purchase and sale transactions."

1.8 Conclusion

Having audited and confirmed the results presented by SoCalGas in the GCIM Year 12 report, DRA recommends that SoCalGas be granted approval of its shareholder reward of $9.8 million and that the reward be recovered through SoCalGas' PGA account.

DRA remains committed to monitoring and evaluating the GCIM, and identifying any modifications that may be required from time to time to further enhance the viability of the mechanism and program. DRA will continue to confer with SoCalGas and other parties on a collaborative basis to modify and enhance the GCIM program as appropriate. All changes or refinements to the GCIM program will ultimately be presented to the Commission for consideration.

Chapter 2

MONITORING AND EVALUATION AUDIT

2.1 Audit Review

DRA conducted a comprehensive review, audit and evaluation of SoCalGas' Year 12 GCIM operations. DRA's workpapers are incorporated herein as exhibits in Appendix A and are an integral part of this report.

DRA's audit confirmed that SoCalGas' GCIM performance in Year 12 yielded a total savings of $69,132,633. These savings are based on the difference between the actual costs of gas, $3,057,709,957 and the GCIM benchmark cost of $3,126,842,590 and are to be shared between ratepayers and SoCalGas shareholders. Of the $69,132,633, $59,329,044 would accrue to the benefit of ratepayers and the remainder $9,803,589 would accrue to the benefit of SoCalGas' shareholders. Table 2-1 and Exhibit A-1 show a summary of SoCalGas savings for GCIM Year 12 and the applicable tolerance band levels for sharing between ratepayers and SoCalGas shareholders.

TABLE 2-1
GCIM Year-12
April 1, 2005 through March 31, 2006
GCIM Reward Calculation

Calculation Categories	GCIM Year-12
Year-to-date-Gain	$ 69,132,633
Amount subject to sharing (0%-1% tolerance band)	29,918,276
Ratepayer Share = 100%	29,918,276
Amount subject to 75%-25% Sharing (1%-5% tolerance band)	39,214,357
Ratepayer Share at 75%	29,410,768
Shareholders' share at 25%	9,803,589
Amount Subject to 90%/10% Sharing (below 5% tolerance band)	0
Ratepayer Share at 90%	0
Shreholders' share at 10%	0
Ratepayers Savings - Year-12	59,329,044
Total Shareholders' share:	9,803,589
Reward calculation Proof:	69,132,633
Other Calculation:	
1.5% Cap on Commodity Costs (Actual)	$ 43,840,424

2.2 Monthly Summary of Benchmark and Actual Costs

Table 2-2 and workpaper Exhibit A show the monthly summary of the gas commodity costs that is the basis for the 1.5% cap on the shareholder reward. The calculated tolerance bands and the related actual commodity cost of gas are measured annually against a benchmark cost. The benchmark is based on the prevailing published natural gas price indices for gas delivered from the mainline and to the California border. Workpaper Exhibits A-3, A-5, and A-8-4b in Appendix A, show the published benchmark commodity costs components. The method by which the benchmark is ultimately developed has been explained in prior DRA reports and is described in SoCalGas Tariffs.[8]

TABLE 2-2
GCIM Year-12
April 1, 2005 Through March 31, 2006
Summary Overview

Month Year	Benchmark Dollars	Actual Dollars	(Over) Under Benchmark	Upper Tolerance Band 2.0%	Lower Tolerance Band 1.0%	Lower Tolerance Band 5.0%	Actual Commodity Costs	Actual Volumes MMBtus
Apr-05	$ 235,015,802	$ 231,859,233	$ 3,156,569	$ 4,459,107	$ 2,229,554	$ 11,147,768	$ 219,798,787	35,045,394
May-05	248,232,420	245,848,678	2,383,742	4,720,601	2,360,300	11,801,502	233,646,300	37,053,129
Jun-05	168,444,295	165,225,258	3,219,037	3,129,312	1,564,656	7,823,279	153,246,548	28,734,314
Jul-05	212,270,703	207,326,372	4,944,331	4,002,545	2,001,273	10,006,363	195,182,935	32,292,068
Aug-05	201,584,314	198,010,311	3,574,003	3,789,782	1,894,891	9,474,454	185,915,087	31,019,795
Sep-05	272,700,890	272,560,687	140,203	5,214,535	2,607,268	13,036,338	260,586,550	32,006,641
Oct-05	359,282,441	359,243,596	38,845	6,939,169	3,469,584	17,347,922	346,919,593	35,784,536
Nov-05	386,951,897	378,079,879	8,872,018	7,543,096	3,771,548	18,857,739	368,282,769	34,559,887
Dec-05	255,700,017	234,297,976	21,402,040	4,917,691	2,458,846	12,294,228	224,482,510	29,143,118
Jan-06	349,016,629	333,868,158	15,148,471	6,771,265	3,385,632	16,928,162	323,414,771	38,403,076
Feb-06	219,542,002	216,978,840	2,563,162	4,188,423	2,094,212	10,471,059	206,858,010	30,937,555
Mar-06	218,101,181	214,410,969	3,690,212	4,161,026	2,080,513	10,402,565	204,361,094	33,988,599
True-up								
Totals	$ 3,126,842,590	$ 3,057,709,957	69,132,633	$ 59,836,552	$ 29,918,276	$ 149,591,379	$ 2,922,694,955	398,968,112

8 Also see Tab E of Joint Motion for Adoption of Settlement Agreement filed on July 5, 2001, A.00-06-023.

2.3 Audit of Benchmark Volumes and Market Costs

DRA confirmed that the current GCIM Year 12 benchmark total gas costs were $3,126,842,590, (as compared to the benchmark total gas costs of $2,277,899,575, reported in GCIM Year 12). The mainline benchmark commodity costs were $2,532,284,164 and the border benchmark costs were as follows: Southern California border costs: $459,609,475; PG&E-/Topock Commodity Costs: a credit of $66,050; the total benchmark border commodity market costs were $459,543, 425; the total benchmark commodity costs for GCIM Year 12 were $2,991,827,588. The volumetric interstate transportation costs were $8,112,850 and the interstate capacity reservation charges were $126,902,152. The aggregate benchmark dollars for GCIM Year 12 were $3,126,842,590.

DRA confirmed the net mainline purchase volumes as 340,055,243 MMBtus and net border volumes were confirmed as 58,912,869 MMBtus. The total benchmark volumes reported were 398,968,112 MMBtus.

In its Application, SoCalGas has reported net purchased volumes of 387 million MMBtus for its retail core operations.[9] DRA confirmed these in Exhibit A-12-3 by netting mainline volumes at the border with shrinkage of 11,468,957 from total benchmark volumes of 398,968,112. The total volumes as reported by SoCalGas were therefore 387,499,155 MMBtus. SoCalGas has reported its total volumes in MMBtus, and at the border, while DRA has reported mainline and border volumes before shrinkage in its calculation of GCIM costs per MMBtu.

Table 2-3 and Exhibit A-3 show the components of mainline and border dollar costs, and Table 2-3a shows the mainline and border volumes before any shrinkage calculation.

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9 SoCalGas Annual Report, Attachment A, para 2, filed June 15, 2006.

Table 2-3
GCIM Year-12
Summary of Benchmark Market Costs
April 1, 2005 Through March 31, 2006

Month Year 2005-2006	Mainline Commodity Costs	So-Cal-Gas Border Costs	PG&E Topock Costs	Border Costs Sub-total	GCIM Benchmark Costs	Transport Benchmark Costs-Sch	Transport Reservation Chg-Sch.	Monthly Benchmark Dollars
Apr-05	$ 166,254,298	$ 56,767,109	$ (66,050)	$ 56,701,059	$ 222,955,356	$ 678,556	$ 11,381,889	$ 235,015,802
May-05	$ 173,629,556	$ 62,400,485	$ -	$ 62,400,485	$ 236,030,041	$ 689,618	$ 11,512,760	248,232,420
Jun-05	$ 143,311,425	$ 13,154,161	$ -	$ 13,154,161	$ 156,465,585	$ 664,733	$ 11,313,976	168,444,295
Jul-05	$ 170,299,601	$ 29,827,664	$ -	$ 29,827,664	$ 200,127,265	$ 700,106	$ 11,443,332	212,270,703
Aug-05	$ 160,368,273	$ 29,120,817	$ -	$ 29,120,817	$ 189,489,090	$ 669,487	$ 11,425,737	201,584,314
Sep-05	$ 212,182,367	$ 48,544,386	$ -	$ 48,544,386	$ 260,726,753	$ 650,645	$ 11,323,492	272,700,890
Oct-05	$ 271,912,607	$ 75,045,832	$ -	$ 75,045,832	$ 346,958,438	$ 829,502	$ 11,494,501	359,282,441
Nov-05	$ 322,125,524	$ 55,029,263	$ -	$ 55,029,263	$ 377,154,787	$ 789,441	$ 9,007,669	386,951,897
Dec-05	$ 256,297,462	$ (10,412,912)	$ -	$ (10,412,912)	$ 245,884,550	$ 738,442	$ 9,077,024	255,700,017
Jan-06	$ 290,189,102	$ 48,374,141	$ -	$ 48,374,141	$ 338,563,243	$ 753,343	$ 9,700,043	349,016,629
Feb-06	$ 176,889,758	$ 32,531,414	$ -	$ 32,531,414	$ 209,421,172	$ 608,046	$ 9,512,784	219,542,002
Mar-06	$ 188,824,192	$ 19,227,115	$ -	$ 19,227,115	$ 208,051,306	$ 340,930	$ 9,708,945	218,101,181
True-up								
Totals	$ 2,532,284,164	$ 459,609,475	$ (66,050)	$ 459,543,425	$ 2,991,827,588	$ 8,112,850	$ 126,902,152	$ 3,126,842,590

TABLE 2-3a
Market Benchmark Volumes
GCIM Year-12 Summary (In MMBtus)
April 1, 2005 through March 31, 2006

Month Year	Mainline Benchmark Volumes	SoCalGas Border Volumes	PG&E Topock Volumes	Total Border Volumes	GCIM-Year-12 Total Volumes
Apr-05	26,645,452	8,409,942	(10,000)	8,399,942	35,045,394
May-05	27,591,342	9,461,787	-	9,461,787	37,053,129
Jun-05	26,406,144	2,328,170	-	2,328,170	28,734,314
Jul-05	27,649,630	4,642,438	-	4,642,438	32,292,068
Aug-05	26,444,647	4,575,148	-	4,575,148	31,019,795
Sep-05	26,161,441	5,845,200	-	5,845,200	32,006,641
Oct-05	28,387,214	7,397,322	-	7,397,322	35,784,536
Nov-05	29,805,739	4,754,148	-	4,754,148	34,559,887
Dec-05	30,269,447	(1,126,329)	-	(1,126,329)	29,143,118
Jan-06	33,324,426	5,078,650	-	5,078,650	38,403,076
Feb-06	26,362,110	4,575,445	-	4,575,445	30,937,555
Mar-06	31,007,651	2,980,948	-	2,980,948	33,988,599
Totals:	340,055,243	58,922,869	(10,000)	58,912,869	398,968,112

2.4 Audit of Actual Gas Costs and Volumes

DRA examined and reviewed the gas commodity costs, interstate volumetric transportation costs, and interstate reservation capacity charges recorded in the GCIM Year 12. DRA verified and confirmed that the recorded costs were properly reported and accounted for under the current GCIM Year 12 program. During the audit review, DRA tracked the actual gas commodity costs, transportation costs and reservation capacity costs by reviewing the data on a monthly basis and performing a random review of final year-end trued-up costs.

The actual confirmed net commodity costs were as follows: (a) interstate mainline purchases of $2,618,105,790; (b) Interstate border purchases of $586,219,536; (c) California and Federal off-shore purchases of $4,811,858; (d) Mainline sales amounting to $99,092,461 (e) Border sales of $173,700,178, which includes sales at PG-Topock of $69,700. The net commodity costs before financial Derivatives and Net Hub Revenues were, $2,936,344,544. The gain from financial derivative transactions included in GCIM Year 12 was $282,684, while hub revenues after overhead costs contributed a net of $13,366,904. The total actual interstate commodity gas costs amounted to $2,922,694,956. The interstate volumetric transportation costs were $8,112,850 and interstate firm reservation capacity charges were $126,902,152. The actual gas costs confirmed by DRA for GCIM Year 12 were $3,057,709,957. Table 2-4 and Exhibits A-4, A-12 and A-15 show the actual gas cost components for GCIM Year 12.

DRA confirmed mainline purchases of 352,050,994 MMBtus and mainline sales of 11,995,751 MMBtus, for net mainline volumes of 340,055,243 MMBtus. DRA also confirmed border purchases of 78,233,066 MMbtus and border sales of 19,320,197 MMBtus, for a net purchase of 58,912,869 MMBtus. The total interstate net volume purchased for GCIM Year 12 was 398,968,112 MMBtus. By comparison, the actual costs for GCIM Year 11 were $2,246,521,573 and actual volumes were 386,956,270. Table 2-4 and workpaper Exhibit A-4, Exhibit A-12-1 and Exhibit A-15 show the actual gas costs and volumes detail for GCIM Year 12.

TABLE 2-4

Actual Gas Costs - GCIM Year-12

April 1, 2005 Through March 31, 2006

Account Description:			
Mainline Purchase Gas Cost:	Net Volumes (MMBtus)		$'s
El Paso Permian		$	511,605,289
El Paso San Juan			1,358,095,119
Transwestern Permian			15,951,027
Transwestern San Juan			543,930,320
Kern River			188,524,035
Sub-total Main Line Commodity Gas Cost	352,050,994	$	2,618,105,790
Border Purchase Gas		$	586,219,536
Federal & California Off-shore gas			4,811,858
Sub-total Border Commodity Gas Cost	78,233,066	$	591,031,394
Add (Deduct)			
Mainline Sales:		$	(99,092,462)
Border Sales:			(173,700,178)
Sub-Total GCIm Year-12 Sales:	**(31,315,948)**	$	(272,792,640)
Add (Deduct)			
Net Hub Revenues		$	(13,366,904)
Derivatives (Not Excluded from GCIM)			(282,684)
Sub-total - Other		$	(13,649,588)
Total Actual Commodity Gas Costs-Year-12		$	2,922,694,956
Transport and Reservation Charges:			
Actual Transport Charges:			$8,112,850
Actual Reservation Charges:			126,902,152
Sub-total Transportation & Reservation Charges			$135,015,002
Round:			**(1)**
Actual Gas Cost GCIM Year-12:	398,968,112		$3,057,709,957
DRA Exhibit A Overview:	398,968,112		$3,057,709,957

2.5 Audit of Mainline and Border Gas Sales

DRA confirmed GCIM Year 12 natural gas mainline sales of $99,092,461, California border sales of $173,630,478; and gas sales at PG&E-Topock of $69,700. In aggregate the total sales confirmed by DRA for GCIM Year 12 were $272,792,640. Table 2-5 shows the detail of Mainline and Border sales for GCIM Year 12.

TABLE 2-5
Summary of Gross Sales-GCIM Year-12
April 1, 2005 Through March 31, 2006

			Volumes (MMBtus)
El Paso Permian	$	(85,555,414)	
El Paso San Juan		(4,224,342)	
Transwestern Permian		(3,863,158)	
Transwestern San Juan		(1,040,694)	
Kern River		(4,408,854)	
Sub-Total - Mainline Sales	$	(99,092,462)	(11,995,751)
SoCalGas Border Sales:			
Border Sales	$	(173,630,478)	
PG&E-Topock Sales		(69,700)	
Sub-Total - Border Sales:	$	(173,700,178)	(19,320,197)
Total Sales - GCIM year-12	$	(272,792,640)	(31,315,948)

2.6 Audit of Interstate Transport Costs

The total interstate volumetric transportation costs for GCIM Year 12 are shown in Table 2-6 as follows: (a) El Paso pipeline $5,233,168; (b) Transwestern pipeline $1,748,094; (c) Kern River $1,446,5942; (d) Mojave-PG&E $159,433; (e) Imbalance Cash-out credit of $474,787. The total interstate volumetric transportation costs for GCIM Year 12 were $8,112,850. Table 2-6 and Exhibit A-6 show the detail of total transportation costs for GCIM Year 12. SoCalGas has been reporting interstate transportation costs for Transwestern Pipeline Company in the Purchase Gas Account as of November 1, 2005. Kern River pipeline charges have been reported in the PGA account since 2004.

El Paso Natural Gas transport charges are currently being reported in the Core Fixed Cost Account (CFCA). However, SoCalGas, in Advice Letter #3644, has indicated that it plans to report these costs in the PGA. A Commission Resolution on this matter is expected shortly.

TABLE 2-6
GCIM Year-12
Detail of Actual Transportation costs
April 1, 2005 through March 31, 2006

Month Year 2005-2006	El Paso Transport D-1	Transwestern Transport D-2	PG&E Park-UnPark D-3	Kern River Transport D-4	FLOW-THROUGH Mojave & PG&E	Imbalance Cashout CR.	El Paso Interruptible	Kern River Interruptible	TransWest. Interruptible	Actual Transport Costs
	a	b	c	d	e	f	g	h	i	J
Apr-05	$ 434,296	$ 166,362	$ -	$ 81,820	$ 1,070	(4,993)	$ -	$ -	$ -	$ 678,556
May-05	441,904	174,479	-	83,809	145	(10,719)	-	-	-	689,618
Jun-05	426,153	165,905	-	82,961	-	(10,285)	-	-	-	664,733
Jul-05	448,226	173,327	-	85,844	-	(7,291)	-	-	-	700,106
Aug-05	410,976	171,454	-	85,992	11,440	(10,374)	-	-	-	669,488
Sep-05	404,497	172,716	-	81,067	22,796	(30,431)	-	-	-	650,645
Oct-05	461,857	182,472	-	84,045	101,127	0	-	-	-	829,502
Nov-05	485,168	108,294	-	173,515	22,464	0	-	-	-	789,441
Dec-05	493,434	111,837	-	175,622	391	(42,842)	-	-	-	738,442
Jan-06	458,271	112,233	-	182,840	-	-	-	-	-	753,343
Feb-06	345,509	98,586	-	163,950	-	-	-	-	-	608,046
Mar-06	422,877	110,429	-	165,476	-	(357,852)	-	-	-	340,930
Totals	$ 5,233,168	$ 1,748,094	$ -	$ 1,446,942	$ 159,433	$ (474,787)	$ -	$ -	$ -	$ 8,112,850

2.7 Audit of Interstate Reservation Costs

DRA confirmed SoCalGas' GCIM Year 12 interstate pipeline reservation capacity charges as summarized in Table 2-7 below. The reservation charges for El Paso Natural Gas Pipeline were $89,010,833 and brokered revenue credits were $634,132, for a net of $88,376,701. Netted against brokered revenue credits of $156,709, the net pipeline reservation charges on Transwestern were $34,053,745. The reservation charges for Kern River pipeline were $4,471,706. Thus, reservation charges for all pipelines and brokered capacity credits are as follows: Reservation Charges of $127,692,993, brokered revenue credits of $634,132 on El Paso pipeline, brokered revenue credits of $156,709 on Transwestern pipeline. In aggregate, the net reservations charges for all pipelines for GCIM Year 12 were $126,902,152. Table 2-7 and Exhibit A-8 series and show the detailed and monthly summary of pipeline capacity charges for GCIM Year 12.

SoCalGas has been reporting interstate reservation costs for the Transwestern Pipeline Company in the Purchase Gas Account as of November 1, 2005. Kern River pipeline charges have been reported in the PGA account since 2004. El Paso Natural gas transport charges are currently being reported in the CFCA. However, SoCalGas, in Advice Letter #3644, has indicated that it plans to report these costs in the PGA. A Commission Resolution on this matter is expected shortly.

TABLE 2-7
Southern California Gas Company
GCIM Year-12
Schedule of Capacity Reservation Charges & Credits
April 1, 2005 Through March 31, 2006

Pipeline Companys' Description:	Reservation Charges	Brokered Revenues	Net Reservation
El Paso Pipeline:	$ 89,010,833	$ (634,132)	$ 88,376,701
Transwestern Pipeline:			
San Juan Lateral	$ 4,887,760		$ 4,887,760
TW Contracts #101188& 101189	6,644,000		6,644,000
TW Contract Nov-2005-Mar-2006	22,678,694	(156,709)	22,521,985
Total Transwestern Pipeline:	$ 34,210,454	$ (156,709)	$ 34,053,745
Kern River Pipeline Company:	$ 4,471,706	-	$ 4,471,706
Total Pipeline Capacity Charges:	$ 127,692,993	$ (790,841)	$ 126,902,152

2.8 Audit of Interstate Pipeline Utilization

During the GCIM Year 7 audit period, SoCalGas and DRA developed a process to track the utilization of pipeline capacity usage. This is the sixth year of reporting on SoCalGas' efforts to maximize its interstate capacity rights in its attempt to purchase lower-priced gas supplies. The new capacity procurement process, as outlined in Commission Decision (D.) 04-09-022, relies on a consultative process between SoCalGas, DRA, The Utility Reform Network (TURN), and the Commission's Energy Division.

DRA's audit confirmed that for GCIM Year 12, SoCalGas nominated 83.75% of its available capacity on El Paso, 81.35% of its available capacity on Transwestern, 98.09% of its available capacity on Kern River, and 100% of its available capacity at the PG&E Topock inter-connection. The total available pipeline capacity was 397,119,733 MMBtus and the nominated pipeline volumes in aggregate were 333,870,824 MMBtus.

Thus SoCalGas attained an overall capacity utilization of 84.07%. However, SoCalGas received only 330,559,344 MMBtus of its nominated volumes from all pipeline capacity for GCIM Year 12. Table 2-8 and workpaper Exhibit A-29 series show a complete reconciliation of GCIM Year 12 capacity utilization.

TABLE 2-8
Reconciliation of Core Capacity Volume Utilization (In MMBtus)
GCIM Year-12
April 1, 2005 Through March 31, 2006

Pipeline Utilization	Net Available	Less: Nominated	Stranded Capacity	Percent % Utilization	Nominted Capacity	Actual Vols Received	Capacity Cut
EPNG-San Juan	180,420,119	181,190,059	(769,940)		181,190,059	178,751,995	2,438,064
EPNG-Permian	101,447,001	54,870,168	46,576,833		54,870,168	54,655,737	214,431
Total EPNG	281,867,120	236,060,227	45,806,893	**83.75%**	236,060,227	233,407,732	2,652,495
Transwestern-San Juan	73,000,000	72,490,584	509,416		72,490,584	72,001,104	489,480
Transwestern-Permian	18,048,294	1,574,920	16,473,374		1,574,920	1,561,285	13,635
Total Transwestern	91,048,294	74,065,504	16,982,790	**81.35%**	74,065,504	73,562,389	503,115
Kern River Pipeline	24,085,300	23,626,074	459,226	**98.09%**	23,626,074	23,523,765	102,309
PG&E Pipeline Interconnect:	119,019	119,019	-	**100.00%**	119,019	65,458	53,561
Totals: (In MMBtus)	397,119,733	333,870,824	63,248,909	**84.07%**	333,870,824	330,559,344	3,311,480

2.9 Audit of the Purchase Gas Account

SoCalGas provided a comprehensive reconciliation of its cost data from the PGA taken from its general ledger. This account reconciles any differences with the GCIM Year 12 commodity gas costs at the end of March 31, 2006.

DRA's workpaper summary shows the reconciliation and timing difference between SoCalGas PGA balancing account and the net commodity gas costs in GCIM Year 12 as follows: the General Ledger PGA balancing account, (a) $2,971,827,724; (b) PGA costs in PGA not reported in GCIM Year-12, $35,480,439; (c) net hub revenues reported in GCIM Year-12, not included in PGA balance account, $13,366,904; (d) Net comparable PGA balance account of $2,922,980,381. (e) Actual GCIM commodity costs from SoCalGas workpaper 1.9 of $2,922,977,640; (f) net timing difference PGA to GCIM Year-12 of $2,741. Table 2-9 and workpaper exhibit A-30 show the details of this PGA GCIM Year 12 timing difference.

The comparable PGA balancing account costs were $2,098,210,206, and the confirmed GCIM Year 11 commodity costs were $2,098,212,450. The PGA timing difference with GCIM Year 11 was confirmed as $2,244.

TABLE 2-9
Southern California Gas Company
Reconciliation of Gas Commodity Costs
PGA Account to GCIM Year 12
For the Period April 1, 2005 - March 31, 2006

Purchase GasCost (PGA) Actual	$	2,971,827,724
Exclude PGA Cost Components not in GCIM Year-12		
Whittier Cushion Gas	$	4,188
Billings to Others		(638,767)
Realized ((Gain) Loss from OTC Derivatives Transactions		7,567,730
Realized (Gain) Los from Exchange-Traded Derivative Transactions		17,853,962
Transportation Charges in PGA Market Gas not in GCIM Commodity Costs		11,294,605
Write-off unpaid Accounts payable accruals not in GCIM Year-12		(601,964)
Prior year California Prod. Adjustment made in PGA-Not GCIM-12		685
Total Excluded PGA Costs not in GCIM Year-12		35,480,439
		2,936,347,285
GCIM Commodity Cost not in PGA		
Net Hub Revenues:		(13,366,904)
Net Comparable PGA Commodity Costs:	$	2,922,980,381
GCIM Gas Commodity Cost (SoCalGas WP 1.9)	$	2,922,977,640
Variance - Commission Fees Timing Difference	$	2,741

2.10 Audit of PGA Financial Derivatives Transactions

DRA reconciled the GCIM Year 12 PGA balance with all transactions recorded and reconciled to the current natural gas year ended March 31, 2006. The overall variance in PGA for GCIM Year 12 was $2,741. The financial derivatives contained within the PGA balancing account for the GCIM Year 12 were reconciled as follows: PGA reported balances within the account as $25,421,701 and the total transactions dedicated to the GCIM Year-12 program and the excluded winter hedge program as reported by SoCalGas as $24,286,536. This variance from the GCIM and winter hedge programs for PGA was $1,135,165.

SoCalGas reported the following details regarding this variance: (a) Futures and Options transactions losses recorded in the PGA in March, 2005 were reported in GCIM Year 12 in April 2005; (b) Broker transaction costs of $6,492 recorded in the PGA during the PBR year 11 for April 2005 through October 2005 were accounted for in GCIM Year 12; (c) The total timing difference between GCIM and winter hedge Year 12 costs and the PGA account was $1,085,983. (d) Swap transaction costs accounted for in GCIM March 2005 were recorded in the PGA account in April 2005 in the amount of $47,145; (e) ICE broker fee credit of $35 in the PGA account in March, 2005 was reversed in the PGA in May 2005; (f) Broker fees in the amount of $2,038 for swap trades made in March 2005, were properly reported in March 2005 for GCIM purposes, but recorded in the PGA in April 2005; (g) The total variance difference in the PGA for futures and options was $1,085,983; (h) The total variance in the PGA for OTC Swap transactions was $49,183; (i) the total variance between PGA balance costs for financial derivatives and GCIM-winter hedge activity programs was $1,135,165. Table 2-10 and workpaper Exhibit A-14-1 and show the reconciliation of these accounts at March 31, 2006.

TABLE 2-10
Reconciliation of Timing Difference GCIM Year-12 & PGA Balance Account Variances
April 1, 2005 through March 31, 2006

Reconciliation of Financial Derivatives: GCIM vs Purchase Gas Balance Account (PGA)	GCIM Year-12 Derivatives	Purchase Gas Balance Account	**GCIM Year-12 Variance**
Exchanged Traded Transactions (Gains) Loss	**$ 16,682,683**	**$ 16,682,683**	**$ -**
Exchanged traded Transaction Costs	**85,297**	**85,297**	**$ -**
April-2005 OTC Cleared trans. gain reported in 4/05 GCIM, 3/05 PGA		**1,092,475**	**$ 1,092,475**
OTC Broker Fees GCIM Year-12 booked in PGA Year-11:		**(6,492)**	**$ (6,492)**
Total Exhange Traded (Gains) Loss:	**$ 16,767,979**	**$ 17,853,962**	**$ 1,085,983**
OTC Swap Transactions (Gains) Loss	**$ 7,510,207**	**$ 7,510,207**	**$ -**
OTC Swap Transactions Costs	**8,341**	**8,341**	**$ -**
Mar-2005 Swap Loss recorded in GCIM Year-11, Booked PGA 4-2005		**47,145**	**$ 47,145**
Broker Fees & Credits recorded in GCIM Year-11, Booked PGA 4-2005:		**2,038**	**$ 2,038**
Total OTC Swap Transactions (Gains) Loss	**$ 7,518,547**	**$ 7,567,730**	**$ 49,183**
Total Financial (Gains) Losses Year-12:	**$ 24,286,526**	**$ 25,421,691**	**$ 1,135,165**

Recap: PGA Variance:	**Variance $**
1.Exchange-Traded Gain PGA-3005 Reported GCIM Year-4-2005	**$ 1,092,475**
2.Swing Swap Loss in GCIM 3-2005, booked in PGA 4-2005	**47,145.00**
3. OTC Broker Fees GCIM Year-12 booked in PGA Year-11:	**(6,492)**
4.Broker Fees & Credits GCIM Year-11, Booked PGA Yr-12	**2037**
Totals:	**$ 1,135,165**

2.11 Reconciliation of Core Fixed Cost Account

DRA has reconciled the CFCA to the interstate reservation capacity charges in GCIM Year 12. In the past, all pipeline reservation charges were recorded in the CFCA. Commission Decision (D.) 02-06-023 approved the settlement agreement recommended by Southern California Gas Company, DRA and TURN. SoCalGas recorded El Paso Excess capacity (>1,044 MMcf/d) according to the terms of the Settlement Agreement which stated that “all related transportation costs associated with the additional core capacity will be treated similar to other gas commodity charges and therefore, be included in the Purchased Gas Balance Account.” These included contracts TSA 9MME and 9MMG on the El Paso pipeline.

In D.04-09-022, the Commission granted SoCalGas approval for the additional capacity that SoCalGas acquired on the Kern River Pipeline. Accordingly, the associated charges have been recorded in the PGA balancing account.

SoCalGas submitted Advice Letters 3443 and 3462 on December 22, 2004 and February 2, 2005 respectively, seeking Commission approval of the renegotiated contracts with El Paso and Transwestern which were set to expire on August 31, 2006 and October 31, 2005 respectively.[10] The Commission approved Advice Letters 3443 and 3462 on September 12, 2005.

In Advice Letter #3528, SoCalGas proposed that all reservation charges for capacity costs, including reservation charges held by SoCalGas under the new contracts be recovered from core procurement customers through the procurement rate and recorded in the PGA. The Commission approved Advice Letter 3528 on October 12, 2005 with an effective date of November 1, 2005. SoCalGas has reported, and DRA has confirmed that beginning November 1, 2005, the new Transwestern Pipeline contracts reservation charges for capacity have been recorded in the PGA balancing account. When El Paso Pipeline existing transportation contracts expire in September, 2006, these new El Paso transportation contracts will also be recorded in the PGA balancing account.

Table 2-11 and Exhibit A-31 show the variance reconciliation of the SoCalGas CFCA to the GCIM Year-12 as follows: (a) Recorded reservation charges in the CFCA for Year 12 were $121,463,451; (b) various inter-account adjustments as shown in Exhibit A-31 were $5,438,701; (c) CFCA at March 31, 2006 was $121,463,451, plus reconciling adjustments applicable to CFCA and GCIM Year 12 of $5,438,701 equaled $126,902,152. GCIM Year 12 reservation charges, as shown in Table 2-7, were $126,902,152. DRA has reconciled and confirmed the CFCA balancing account with costs report in GCIM Year-12.

10 Advice Letter 3443, 12/22/2005; Advice letter 3462, 2/2/2005 & Advice Letter 3528, 10/2005, (Effective Date: 11/1/2005).

TABLE 2-11
Reconciliation of Reservation Charges Recorded in
Core Fixed Cost Balancing Account (CFCA) to GCIM Year 12
4/1/05 -3/31/06

Recorded Reservation Charges in CFCA 12 months ended 4/3/2006	**$**	**121,463,451**
Adjustments:		
Exclude March 2005 Lag	**$**	**8,888**
Reverse April 2006 Estimate		**(7,718,108)**
Payments to CAT in CFCA not in GCIM		**(168,918)**
Kern River reservation charges in GCIM not CFCA		**4,471,706**
TW reservation charges in GCIM not in CFCA		**6,644,000**
El Paso Excess Capacity in GCIM not in CFCA		**2,191,534**
Revised El Paso capacity allocated to the core, reflected in GCIM , not CFCA		**9,598**
Rounding		**1**
Sub-total-Adjustments:		**5,438,701**
Total CFCA Account Adjusted:	**$**	**126,902,152**
GCIM Year 12 Core Reservation Charges (Table 2-7)	**$**	**126,902,152**

2.12 Audit of Net Hub Revenues

SoCalGas optimizes the use of the rights and assets assigned to the retail core including its storage inventory, injection and withdrawal rights, and flowing supply through the use of its California Energy Hub. Subject to established tariffs, hub transactions and fees are based on existing market conditions and are completed on a non-discriminatory basis. Hub transactions continue to contribute to the overall lower gas costs achieved by SoCalGas by using assets not needed for core reliability.[11]

SoCalGas' gross hub revenues for GCIM Year 12 were $13,873,238 and hub overhead expenses were $506,334, for net hub revenues of $13,366,904. By comparison, GCIM Year 11 gross hub revenues were $13,902,776 and hub overhead expenses were $742,823, for net hub revenues of $13,159,953. The SoCalGas GCIM Year 12 net hub revenues are reported in Exhibit A-14 and Table 2-12 below.

11 SoCalGas Annual Report, Attachment a, Dated June 15, 2005, page 5, para 1.

TABLE 2-12
GCIM Year-12
April 1, 2005 through March 31, 2006
Summary of Hub Revenues

Month Year	Gross Hub Revenues		Overhead Expenses		Net Hub Revenues	
Apr-05	$	(1,000,730)	$	35,024	$	(965,706)
May-05		(363,489)		29,870	$	(333,619)
Jun-05		(922,793)		37,163	$	(885,630)
Jul-05		(1,449,454)		29,387	$	(1,420,067)
Aug-05		(645,599)		27,997	$	(617,602)
Sep-05		(1,164,885)		154,619	$	(1,010,266)
Oct-05		(823,078)		46,706	$	(776,372)
Nov-05		(150,087)		31,488	$	(118,599)
Dec-05		(1,287,796)		25,712	$	(1,262,084)
Jan-06		(2,499,511)		28,783	$	(2,470,728)
Feb-06		(1,425,405)		27,361	$	(1,398,044)
Mar-06		(2,140,412)		32,224	$	(2,108,188)
Totals:	$	(13,873,238)	$	506,334	$	(13,366,904)
A-12	$	(13,366,904)	SoCalGas Module			

2.13 Audit of Financial Derivatives

SoCalGas engaged in the use of financial derivatives on behalf of its core customers in an attempt to reduce and/or stabilize core commodity gas costs. These hedging costs were originally contained within the GCIM. During the period April 2005 to March 2006, there was an over-all gain of $282,684 for derivatives allowed in the GCIM program for Year 12. Details were as follows: (a) revenues from exchange traded transactions were $1,406,360, transaction fees were $20,128, over-the-counter swaps losses were $1,095,207; and transaction costs associated with over-the-counter transactions were $8,341. Table 2-13 and Exhibit A-17 show the summary of these transactions applicable to GCIM Year 12.

Early in GCIM Year 12, SoCalGas filed a petition for modification of D.02-06-023 to undertake an expanded level of hedging on behalf of its core gas customers for Winter 2005-2006 and to treat all of the associated hedging costs and benefits outside of its current GCIM.[12] In D.05-10-043, the Commission approved the hedging plan submitted by SoCalGas for Winter 2005-2006 indicating that it would help safeguard core customers from high natural gas prices for the coming winter at a moderate cost to ratepayers. SoCalGas reported its actual average commodity cost, not including transportation costs, was $7.54 per MMBtu. This was $0.18 per MMBtu below the benchmark average commodity cost, not including transportation costs, of $7.72 per MMBtu.[13] DRA has confirmed the cost of the winter-hedge program for GCIM Year 12. Derivatives excluded from GCIM Year 12, but included in the PGA for Year 12 were as follows: (a) winter hedge financial transactions that were exchange traded yielded a loss of $18,089,043; (b) transaction fees paid amounted to $65,168; and (c) over-the-counter swap losses that were excluded from GCIM-12 program were $6,415,000. The cost of transactions dedicated to the winter-hedge program of 2005-2006 was therefore $24,569,211.

TABLE-2-13
Financial Derviatives (Gains) Losses In Southern California Gas Account
April 1, 2005 Through March 31, 2006

Account Description		$'s
I. All Financial Transactions Included in GCIM Year-12 Program		
Exchange Traded (Gains) Losses	$	(1,406,360)
Transaction Costs		20,128
Over-the-Counter Swap (Gains) Losses		1,095,207
Transaction Costs		8,341
Derivatives Applicable to GCIM Year-12 Reward	$	(282,684)
II. All Financial Transaction Not Included In GCIM Year-12 Program		
Winter Hedge Exchange Traded (Gains) Losses	$	18,089,043
Transaction Costs		65,168
Winter-Hedge OTC Swap (Gains) Losses Excluded from GCIM year-12		6,415,000
Derivatives Excluded from GCIM Year-12	$	24,569,211
Total Financial Derivatives Reconcilied in PGA Balance Account	$	24,286,527

12 SoCalGas' Petition for Modification was filed jointly with San Diego Gas and Electric Co.
13 SoCalGas Annual Report, Attachment A, para 2, page 2.

2.14 Core Storage Inventory on October 31, 2005

SoCalGas reported in its Annual Report, dated December 31, 2005, that it reached its core physical inventory target in compliance with D.02-06-023. SoCalGas' core physical inventory at October 31, 2005 was 68.5 Bcf, including 0.5 Bcf of Core Aggregation Transportation volumes, but excluding 0.7 Bcf of net Hub parks.[14]

As shown in Table 2-14 and work paper Exhibit A-32, DRA's audit confirms that the total physical core storage inventory on October 31, 2005 was 68.5 Bcf for GCIM Year 12.

TABLE 2-14
Southern California Gas Company
Core Storage Inventory at October 31, (In Bcf)
for theGCIM Years 2003, 2004 & 2005

Description	GCIM Year-10 Oct-03	GCIM Year-11 Oct-04	GCIM Year-12 Oct-05
Core-Inventory	69	64.8	68.1
Core-Aggregation Inventory	0.5	0.5	0.4
Total Core Storage Inventory	69.5	65.3	68.5

Note 1 Net Park Inventory of 0.7 Bcf excluded N-1

2.15 Pipeline Procurement Activity

During GCIM Year 12, Gas Acquisition purchased 387 million MMBtus for its core ratepayers. SoCalGas' interstate capacity rights on El Paso, Transwestern and Kern River pipeline systems enabled the core's requirements to be met largely through basin purchases rather than purchases at the California border. In GCIM Year 12, SoCalGas maintained a gas supply portfolio primarily weighted toward long-term supply

14 SoCalGas Annual Report, Attachment A, dated June 15, 2006, Attachment A Page 4, para 3.

agreements (63%). Month to month and daily gas purchases, net of sales accounted for 37% of the portfolio.[15]

2.16 Summary of DRA Audit Findings

- DRA confirmed that actual gas costs for GCIM Year 12 were $3,057,709,957 and that market benchmark costs were $3,126,842,590. By comparison, the actual gas costs for GCIM Year 11 were $2,246,521,573 and the benchmark costs were $2,277,899,575.
- DRA confirmed that SoCalGas' Year 12 GCIM performance yielded aggregate savings of $69,132,633 as compared to $31,378,002 for SoCalGas' GCIM Year 11.
- SoCalGas reported in Table 1 of its annual report for the GCIM Year 12 gas year that it acquired natural gas at $69.1 million below the Benchmark in Year 12. The average purchase volume reported at the border after shrinkage was 387 million MMBtus and the net gas commodity costs for GCIM Year 12 were $2,923 million for an average commodity cost excluding transportation costs of $7.54 per MMBtu. Correspondingly, the benchmark gas commodity costs were $2,992 million dollars for an average benchmark cost excluding transportation costs of $7.72 per MMBtu.[16]
- DRA confirmed that actual commodity costs of $2,922,694,955 when combined with hub revenues of $13,366,904 and a gain from financial derivatives transactions (included in the GCIM) of $282,684 yielded commodity costs of $2,936,344,543.
- DRA used actual market volumes of 398,968,112 MMBtus while SoCalGas, in their computations, used post-shrinkage volumes of 387,499,155 MMBtus.
- The total actual gas costs for GCIM Year 12 was confirmed at $3,057,709,957. This included the actual commodity costs of $2,922,694,955, interstate transport costs of $8,112,850, and reservation charges of $126,902,152.
- DRA confirmed that SoCalGas net hub revenues from park and loan operations were $13,873,238, less overhead expenses and annual bonus compensations of $506,334. Net hub revenues for GCIM Year 12 were $13,366,904. This compared to net hub revenues for GCIM Year 11 of $13,159,953.

15 SoCalGas Annual Report, June 15, 2006, Attachment A, Pages 3-4.

16 SoCalGas Annual Report, June 15, 2006, Attachment A, Page 1-2.

- DRA confirmed that losses from over-the-counter swap positions were $1,095,207 and related transaction fees were $8,341. DRA also confirmed that gains from NYMEX futures transactions for GCIM Year 12 were $1,406,360 and related transaction fees were $20,128. The overall net gain from options and swap positions and NYMEX futures after taking into consideration transaction fees was $282,684.
- DRA confirmed that SoCalGas spent $24,569,211 for winter 2005-2006 financial hedges of the maximum authorized level of $55 million.
- DRA confirmed the following core pipeline capacity utilization volumes. On El Paso Pipeline, the net contract capacity was for 281,867,120 MMBtus. SoCalGas nominated 236,060,227 MMBtus but received only 233,407,732 MMBtus. On Transwestern Pipeline, the net contract capacity was 91,048,294 MMBtus, SoCalGas nominated 74,065,504 MMBtus, but received only 73,562,389 MMBtus. At the PG&E Topock interconnect, SoCalGas had a net contract capacity of 119,019 MMBtus. It nominated and received virtually 100% of its contract capacity volumes. On Kern River pipeline, the net contract capacity available to SoCalGas was 24,085,300 MMBtus. It nominated 23,626,074 MMBtus of this capacity, but received 23,523,765 MMBtu. In aggregate, SoCalGas had capacity contracts for 397,119,733 MMBtus. It nominated 333,870,824 MMBtus of its contracted capacity, but received only 330,559,344 MMBtus. The capacity cut was 3,311,480 MMBtu.
- SoCalGas confirmed its Core Storage Inventory at October 31, 2005 for the GCIM Year 12 report. The core inventory was 68.1 Bcf and the Core-Aggregation Inventory was 0.4 Bcf. The total inventory reported was 68.5 Bcf. This is excluding 0.7 Bcf of net hub parks.
- DRA reconciled and confirmed the PGA variance of $1,135,165 for GCIM Year 12 and winter hedge transactions at March 31, 2006.
- DRA has reconciled the variance between the Core Fixed Cost Account as follows: CFCA, $121,463,451; add variance of $5,438,701, total CFCA account at March 31, 2006, $126,902,152. The total interstate reservation charges reported in GCIM Year-12 at March 31, 2006 are $126,902,152.
- The Commission, through its advice letter approvals, has authorized SoCalGas to report contract interstate capacity charges of Transwestern Pipeline and Kern River

pipeline in the PGA as of November 1, 2005. The Commission has also authorized SoCalGas (through the advice letter process) to report capacity costs for new contracts in the PGA when these contracts come into effect in September 2006. This is an accounting method change for SoCalGas' accounting department. While the process for reporting and reconciling the PGA and CFCA balancing account will change, the process for reporting reservation charges in the GCIM will not be affected.